STANDING COMMITTEE ON JUSTICE POLICY

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DOCUMENTS PROVIDED BY COLIN ANDERSEN, CEO, ONTARIO POWER AUTHORITY

TUESDAY, APRIL 30, 2013

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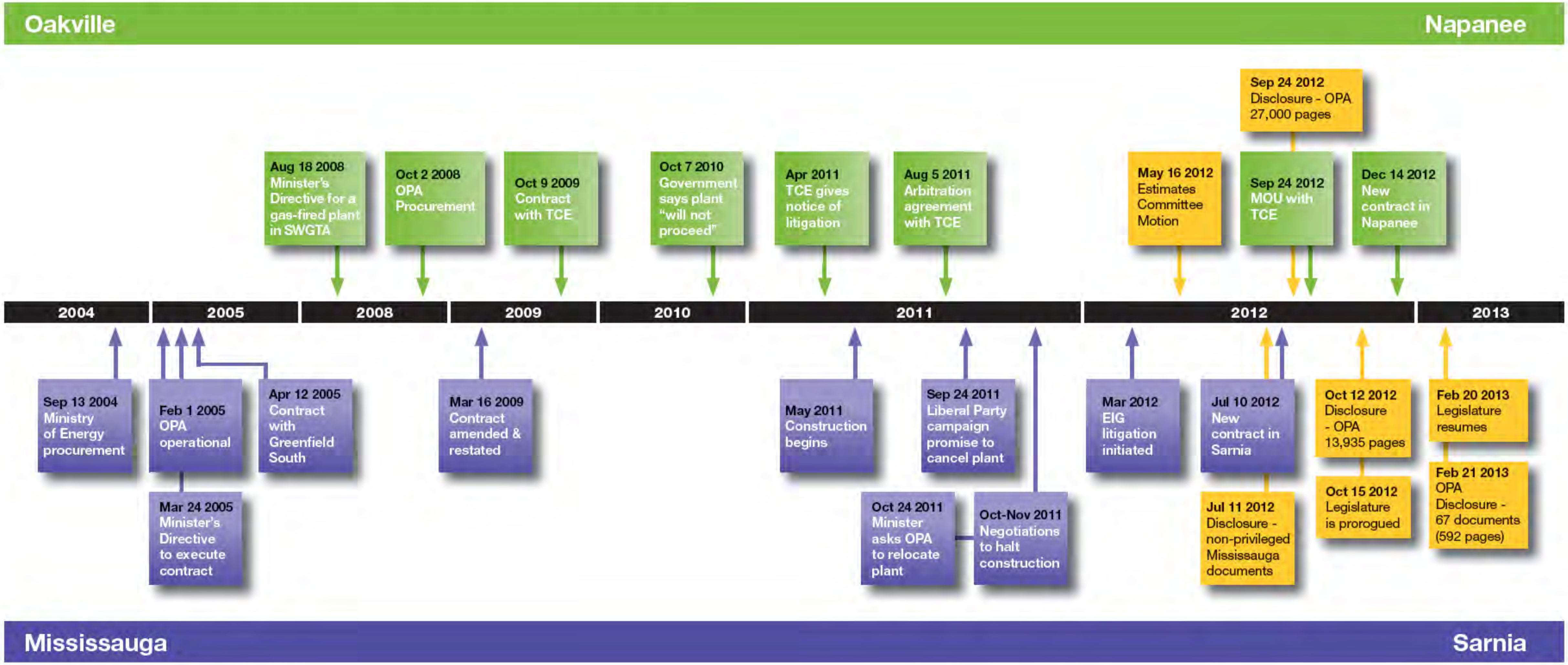
Tab 1

Ontario Power Authority

Gas Plant Cancellation and Relocation Chronology



- Mississauga/Sarnia (Greenfield South)
- Oakville/Napanee (TCE)
- Disclosure

April 2013

Tab 2

April 29, 2013

The Costs of Relocating the Oakville Generation Station

Prepared for the Ontario Power Authority

NERA
Economic Consulting

LEGAL NOTICE

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Contents

I. Executive Summary

NERA Economic Consulting (NERA) was retained by the Ontario Power Authority (OPA) to quantify the cost of the Ontario Government's October 2010 decision to halt development of the Oakville Generation Station (Oakville or OGS). OGS was being developed as a 900 MW natural gas-fired combined cycle generation plant. The decision to not proceed with development of the plant in Oakville eventually led to the relocation of the plant. The Government announced on October 7, 2010 that the Oakville power plant was not moving forward, and, at the Government's direction, the OPA informed TransCanada Energy, Ltd. (TCEL) that it would not proceed with the Southwest GTA Clean Energy Supply Contract, which was the contract applicable to OGS. Further, the OPA acknowledged that TCEL would be entitled to reasonable damages from the OPA including the anticipated financial value of the contract.

At the time, TCEL had expended funds and made commitments that were associated with various goods and services, some which could potentially be reused for a new power plant at another site and some which could not. TCEL ceased development in Oakville, and negotiations between the OPA and TCEL commenced to terminate the contract on mutually acceptable terms. These negotiations sought to minimize costs by exploring options under which TCEL could reuse as much equipment as possible and explored the possibility of TCEL constructing a 400-500 MW peaking plant in Cambridge. In August 2011, it was mutually apparent that an agreement would not be reached, and the OPA, the Government and TCEL entered into an Arbitration Agreement. The arbitration process began in 2012, but was paused in the summer of 2012 to allow negotiations to resume. In September 2012 an agreement was reached between the OPA and TCEL that effectively resulted in the OGS project being relocated to an Ontario Power Generation (OPG) site in the eastern Ontario town of Napanee and that resolved the issue of damages that TCEL was entitled to.

NERA quantified the economic costs resulting from the relocation of the plant. These costs included compensation for goods and service expended to develop the Oakville plant. The single largest component of the relocation impact is a cost savings due to a reduction of the Contingent Support Payments (CSPs) of $670 million in net present value (NPV) terms. This savings is more than offset by a number of costs including: a reimbursement to TCEL of $250 million

(nominal) for costs that were incurred or committed to, the bulk of which is related to equipment and works that will be used at the new site;[1] $350 million (NPV) in reimbursable costs for gas and delivery management services; a cost of the advancement of transmission facilities to maintain reliability of $88 million (NPV); the impact of additional transmission losses of $24 million (NPV); the purchase of additional capacity in 2017 and 2018 at a cost of $153 million (NPV); and payment of other reimbursable capital costs of $42 million (NPV).

NERA considered the magnitude and timing of direct payments and other associated costs, as well the CSPs under the contractual agreement reflecting relocation and the contract that would have been in place assuming no relocation. The costs under both alternatives were determined by month and converted to a net present value using a nominal Social Discount Rate (SDR) of approximately 6%. The use of an SDR is universal practice when governments make this type of decision and a nominal SDR of 6% is an appropriate value. The resulting net present value of costs from relocating the Oakville plant in today's dollars is approximately $241 million.

[1] The $ 250 million reimbursement includes approximately $ 200 million related to the combustion turbines ordered for the project. These will be used at the relocated site and the OPA will ultimately be compensated for this payment through a reduced NRR under the new contract, and NERA accounted for this effect.

II. Scope of Assignment and Description of Methodology

A. Scope of Assignment

NERA was retained by the Ontario Power Authority (OPA) to review and calculate the costs associated with the relocation of the Oakville Generating Station. OGS was being developed by TCEL as an approximately 900 MW natural gas-fired combined cycle plant located in Oakville. TCEL executed the Southwest GTA Clean Energy Supply Contract (SWGTA CES) on October 9, 2009, obligating it to develop and operate the OGS facility for 20 years with an initial operation date of February 8, 2014.

The SWGTA CES Contract follows the contractual model established by the Ministry of Energy for the 2004 Clean Energy Supply request for proposals. The contract was developed to encourage supplier participation in Ontario's competitive energy market. Among the features of the contracts are the following:

- Delays related to obtaining permits from governmental authorities can be events of Force Majeure and may entitle the supplier to delay the initial commercial operation of the plant;
- The supplier is obligated to build and operate the plant and is entitled to market the electricity generated by the plant and retain the associated revenues;
- The supplier bears all costs of constructing, maintaining and operating the plant including all fuel supply costs; and,
- The supplier is entitled to receive a Contingent Support Payment (CSP) – the CSP is based on the difference between the Net Revenue Requirement (NRR) that the supplier bid to win the RFP and the Imputed Net Revenue (INR) or amount that the supplier each month has the opportunity to earn in the Ontario energy market after considering the cost of fuel. If the INR exceeds the NRR, the supplier must make a Revenue Sharing Payment based on the amount by which the INR exceeds the NRR.

The Government announced on October 7, 2010 that the Oakville power plant was not moving forward, and, at the Government's direction, the OPA informed TCEL that it would not proceed with the Southwest GTA Clean Energy Supply Contract, which was the contract applicable to OGS. The OPA acknowledged that TCEL would be entitled to reasonable damages from the

OPA including the anticipated financial value of the contract. The parties began to negotiate damages and possible modification and relocation of the facility.

In December 2012, after more than two years of negotiations and arbitration, the OPA and TCEL finalized an agreement to terminate the SWGTA CES contract and replace it with a new CES Contract dated December 14, 2012 (New CES Contract) related to a 900 MW natural gas-fired generation plant in Napanee. TCEL was compensated $250 million for expenditures that had been made or committed to. These include site specific costs for goods and services that could not be reused at the new location, as well as costs for items that could be reused. The New CES Contract reflected the reduction in costs that would result from the OPA having compensated the supplier for equipment or work that could be repurposed and changes in costs resulting from the change in location and resulting change in the commercial operation date to December 31, 2018. Many aspects of new and relocated plant/contract are very similar; hence, herein the chain of events resulting in termination of the SWGTA CES and its replacement with the New CES is referred to as the relocation of OGS.[2]

NERA was charged by the OPA with the development of an independent determination of the costs of relocating the plant. In determining the costs, NERA utilized payment information supplied by the OPA, settlement documents and the original and amended contracts. NERA exercised its independent judgment and economic expertise in determining the scope of costs to consider, the methodology for assembling the costs and the discount rate. NERA's objective is to determine the total costs associated with the relocation from an economist's perspective and to clearly present that total in this report and describe the methodology that it developed and utilized. Appendix A presents NERA's qualification to undertake this assignment.

B. Methodology

The methodology used by NERA was to first identify by month all costs that would have resulted under the contract effective prior to relocation, the SWGTA CES, assuming that the relocation had not been initiated by the Government and assuming that the supplier (supplier is used herein to refer to TCEL in its role as counterparty to the SWGTA CES) performed its

[2] The aspects that have changed—the location, timing and parts of the payment structure—NERA accounts for in its modelling.

obligations as envisioned by the contract. These costs consist of the CSPs that the OPA would be required to make under the contract. In developing these costs NERA assumed that OGS, if not relocated, would have begun commercial operation in March 2014, the first full contract month after the commercial operation date in the SWGTA CES. While TCEL had informed the OPA of Force Majeure events related to obtaining governmental approvals and delays were possible, no new milestone dates had been established. NERA then identified categories of cost changes that result from the relocation. These consist of the following:

- Avoided CSPs made by the OPA between the pre-relocation and revised commercial operation dates resulting from the relocation;
- Incremental CSPs made by the OPA in the period 20 years after the pre-relocation commercial operation date and 20 years after the revised commercial operation date;
- Payments made in conjunction with the reimbursement of the costs of equipment, works and other financial commitments made to TCEL. We note however that the true net cost of this reimbursement is lower than the amount directly paid to TCEL, as the subset of payments related to repurposed equipment leads to lower NRRs and hence lower CSPs during the term of the new contract compared to CSPs during the term of the contract in effect prior to the relocation agreement;
- Payments made over the contract term in addition to the NRR – these are payments made to TCEL related to Reimbursable Capital Costs and Gas Delivery and Management Service (GDMS) costs;
- The cost of replacement capacity required by the later online date for the project (assumed to be the COD milestone date of December 31, 2018);
- The costs of the advancement of transmission facilities directly occasioned by the relocation; and
- The cost of additional transmission losses that result from relocation.

These costs were estimated by month from the date of the initial cash flow in any of the above categories and were discounted to a single net present value expressed as of the date of this report, April 2013.

NERA developed this methodology as it believes the methodology most accurately represents the economic costs of relocating the projects. This is the case because:

- The CSP represents the economic cost of having the plant constructed and operated in the location and on the time schedule in each scenario. The NRR (which covers all plant fixed costs) is offset on a cost basis by energy cost savings resulting from displacement of more expensive energy sources, where these savings are measurable as the INR[3]. Therefore only the portion of the NRR not offset by energy cost saving (not offset by the INR) is an economic cost;

- The methodology calculates the net present value of the CSP under two cases – with and without relocation;

- Payments for Reimbursable Capital Costs and GDMS represent additional costs that would not have been needed in the Oakville location;

- Payments for costs or commitments that cannot be repurposed represent an economic cost of relocation in that absent the decision to relocate, these costs would not have been incurred and the goods and services that are associated with such costs would have been usable;

- The acceleration of transmission investments that is required because of the decision to relocate is an economic cost as absent such a decision these costs would have been incurred later and there is time value to expenditures;

- The cost of additional transmission losses that result from relocation represent the cost of power production that would not have been incurred had relocation not occurred;

- But for result of the relocation and delay, Ontario would not have required over 500 MW of capacity in 2017 and 900 MW of capacity in 2018 that it currently must acquire, and obtaining such capacity represents an economic cost; and

- Discounting the costs to a common point in time is required for purposes of measuring the economic costs, as the timing of costs incurred differs significantly in the non-relocation and relocation cases, and the time value of money represents an economic cost.

We have elected not to include in the non-relocation scenario a cost of repowering or obtaining replacement capacity after the SWGTA CES Contract expires. There is a period of approximately five years after the SWGTA CES Contract expires during which the relocated plant is still under the New CES Contract, while the plant in the original location would not be under contract and where the plant in the original location would be twenty years old and could

[3] Energy revenue net of operating costs that the facility would earn. While the INR is a contractually defined term, the INR is intended to and assumed to reflect the actual net revenue that the plant would earn in the market and hence the fuel and other operating cost savings from the plant's operation.

require additional capital investment. However, given the uncertainty as to the investment that the plant would require and the load and capacity balance in the province at the time, we do not include a cost for this item. This results in a conservative, meaning leaning to the higher side, quantification of relocation cost as the cost of replacement or repowering would increase the cost of the non-relocation scenario and hence reduce the cost of relocation.

III. Summary of Relocation Costs for OGS

The table below presents the costs of relocation for OGS. On a net present value (NPV) basis as of April 2013, the relocation of OGS results in an overall net cost of approximately $241 million. The single largest component of this cost is a reduction of the CSP of $670 million in net present value terms. This savings is offset by reimbursement to TCEL of $255 million NPV ($250 million nominal) for costs that were incurred or committed to, including over $200 million for equipment and works that will be used at the new site and that offset the NRR under the new contract. Additionally, the relocation requires substantial advancement of transmission facilities to maintain reliability in the SWGTA. The NPV cost of this advancement is $88 million. The impact of additional transmission losses was calculated to be $24 million (NPV). The new contract associated with relocation of OGS provides for reimbursement of certain capital costs estimated at $42 million in present value and payments to TCEL of the costs of GDMS, estimated at approximately $350 million in net present value terms. Finally, the purchase of additional capacity in 2017 and 2018 results in a cost of approximately $153 million (NPV). A description of the key assumptions used to develop the cost summary follows the table.

Summary of Costs Related to the Oakville Generation Station Relocation
All costs are in CAD, Expressed on a Net Present Value Basis (Discounted to April 2013)

	Costs		
Component	**With Relocation**	**Without Relocation**	**Delta**
Net Revenue Requirement	*1,430,426,148*	*2,155,842,249*	*-725,416,101*
Imputed Net Revenue	*154,039,214*	*208,957,245*	*-54,918,032*
Contingent Support Payment	1,276,386,935	1,946,885,004	-670,498,069
Reimbursement for Costs Incurred	254,903,206	0	254,903,206
Transmission (Reflects Acceleration)	237,290,016	149,267,839	88,022,177
Incremental Transmission Losses	24,077,556	0	24,077,556
Replacement Capacity Costs	152,738,224	0	152,738,224
Incremental GDMS Costs	350,009,682	0	350,009,682
Reimbursable Capital Costs	41,716,520	0	41,716,520
Total Payments	**2,337,122,138**	**2,096,152,843**	**240,969,294**

Sources: TransCanada Energy Ltd. Contracts, as Amended; TransCanada Energy Ltd. Reimbursement Agreement; and other documents provided by the OPA; Forecasted CPI from Conference Board of Canada; Historical CPI from Statistics Canada; Foreign Exchange Rates from Oanda; Gas Price Forecasts from Sproule; Historical Power Prices from IESO.

Material assumptions and data sources used to develop the economic cost impact of relocation for OGS are as follows:

- The NRR is developed from the SWGTA CES Contract (dated October 9, 2009) and the New CES Contract (dated December 14, 2012) between the OPA and TCEL.

- The INR is estimated based on historical average INRs ($/MW) payable to similar facilities over the past four years, escalated based on a Dawn gas price forecast available from Sproule. The INR has been adjusted for the fact that the New CES Contract provides for a 160 MMBTU higher heat rate in all seasons for determining the INR, which lowers the INR in the relocation case.

- The CSP is simply the NRR less the INR.

- Payments for costs incurred and committed to by TCEL prior to relocation are from the Reimbursement Agreement between the OPA and TCEL dated December 14, 2012. Of this $250 million, over $200 million reduces the NRR under the new contract.

- The cost of replacement capacity for June 2017 through May 2018 was calculated using 550 MW multiplied by the estimated CSP of the non-relocated facility for that time period. The cost of replacement capacity for June 2018 through December 2018 was calculated using 900 MW multiplied by the estimated CSP of the non-relocated facility for that time period. The replacement capacity volumes are developed from an OPA presentation outlining the impact of the relocation on the 2012 APPRO supply and demand balance and represent capacity deficits occasioned by the relocation. The CSP from the OGS contract is used a proxy for the cost of capacity that OPA would otherwise acquire.

- GDMS costs were developed based on an analysis of Union Gas and Trans Canada Pipeline tariffs and charges for transportation, storage and balancing provided by the OPA and reviewed and confirmed by NERA. These charges are substantial, beginning at over $36 million annually in the first full year of operation at Napanee. NERA believes that the estimated GDMS cost are an upper bound as TCEL may realize revenues from selling gas transportation capacity that it does not use and these would flow back to the OPA. Additionally, over the contract life it may be possible that lower cost transportation options are possible and the OPA has the right to periodically review the GDMS plan.

- Reimbursable Capital Costs are covered by Attachment Y to the New CES Contract. The OPA has informed NERA that Supplier Connection Costs may be as high as $50 million and NERA has used this upper bound in the relocation estimate. NERA has assumed that all $5 million potentially reimbursable as OPG Site Costs will be expended. However, TCEL has advised the OPA that it is not yet determined if it will be required to make a contribution in aid of construction that would result in Pipeline Costs being reimbursed, and hence NERA has not included any amount for Pipeline Costs. All the above estimates are in nominal dollars and are lower when stated in present value terms.

- The cost of transmission acceleration is estimated as $88 million (NPV). This is due to an estimated 10 year acceleration of the Trafalgar TS 500-230 kV auto overload project. NERA also included assumed additional project maintenance costs due to the acceleration.

- The cost of transmission losses were estimated using the historical (last four years) HOEP during high load hours and assuming a 30% capacity factor for Oakville based on a review of the historic operation of similar units. The cost of losses was escalated using a Dawn gas price forecast available from Sproule. We used an estimate of 15 MW of additional losses, an assumption that was provided by OPA.

The discount rate used was 6% (approximately 4% real discount rate). The rationale for discounting and the election of the discount rate are discussed in the following section of the report.

IV. Selection of the Appropriate Discount Rate

An important element of the impact of the relocation is the timing of the costs that are incurred. The timing issue goes both ways. In the relocation scenario, certain costs such as settlement payments or payments for goods and service that cannot be reused, which would have been paid over time absent relocation, are accelerated by relocation. Others such as the CSPs are delayed by relocation. Nonetheless it is important to account for timing impacts and this is done by the use of a discount rate.

As expressed succinctly in a paper entitled "Social Discount Rates for Canada"[4], "There is general agreement in the policy analysis community that future impacts should be discounted at the social discount rate (SDR) – the rate at which society discounts future costs and benefits and converts them into present values." Universally, governments evaluate investments (e.g., infrastructure building) or regulatory actions (e.g., environmental regulations) by applying SDRs. The SDR is used to generally represent the trade-off deemed appropriate for society at large resulting from governmental decisions that affect the current use of resources and the use of such resources in a way that provides future benefits. In the instant application, the Ontario government made decisions that eventually led to the relocation of the Oakville plant, which results in certain near term expenditures that are then partially offset by differing costs of providing electricity supply over a long period in the future. The impact of this type of decision can only be quantified in a manner consistent with how Ontario and in fact all governments view the impacts of their decisions, which is by considering the time pattern of costs and applying a SDR.

While the need to use an SDR should be clear, the selection of the appropriate SDR is subject to differing views. Prior to 2007, the Treasury Board Secretariat (TBS) in Canada required the use of a real SDR of 10%. The real SDR is the SDR without inflation. The nominal SDR, or SDR that would be applied to cash flows that reflect inflation, can be approximated by adding the projected inflation rate to the real SDR. Hence if the long term inflation expectation was 2%, a real SDR of 10% would result in a nominal SDR of 12%. This real SDR has since been lowered

[4] Social Discount Rates for Canada, September 28, 2008, by Anthony E. Boardman, University of British Columbia; Mark A. Moore, Simon Fraser University; and, Aidan R. Vining, Simon Fraser University, page 3.

by the TBS. Similarly, in 2003 the UK reduced the real SDR it uses from 6% to 3.5%, and in 2005 a group of experts commissioned by the Ministry of Finance recommended that France reduce its real SDR from 8% to 4% for most public projects.[5] In their cited paper, Boardman, Moore and Vining recommend a 3.5% real SDR for non inter-generational analyses. The OPA utilized a real SDR of 4% in 2007 when evaluating gas-fired and nuclear generating resources. In its recent Integrated Resource Plan, the Tennessee Valley Authority, a large federal power entity in the United States used a nominal discount rate of 8%, equivalent to a real discount rate of 6%.

In developing this estimate of the cost of relocation, NERA utilized a nominal discount rate of 6%. A nominal rate is used as the discount rate and applied to nominal cash flows. This nominal rate is equivalent to a real SDR of just under 4%, a value consistent with that used by the OPA in planning analyses. This value is generally consistent with real SDRs that are widely used for analyses of this nature by a variety of governments.

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[5] Ibid, page 3.

V. Appendix A – NERA Qualifications to Analyze Relocation Costs

NERA Economic Consulting is one of the world's leading international economic and financial consulting firms and is focused on the application of economics and finance to complex business and risk management issues. Clients include multinational corporations, governments, law firms, regulatory agencies, trade and industry associations, and international agencies.

NERA was founded in 1961 and employs over 400 professional economists in offices throughout North America, Europe and Australasia. The firm and its professionals are recognized around the world for work in valuation, risk assessment and management, antitrust/competition policy, market strategy and design, commercial damages, regulation, and product strategy. NERA has also developed sophisticated modeling techniques to appropriately assess the economic impact of risk management and cash flow volatility on business decision-making.

Our professionals devise practical solutions to highly complex business and legal issues arising from competition, regulation, public policy, strategy, finance and litigation. We provide our clients with advice and insight that reflect our specialization in industrial and financial economics as well as over 50 years of practical experience. We are widely recognized for our independence. Our clients come to us expecting integrity; they understand this sometimes calls for their willingness to listen to unexpected or even unwelcome news.

NERA has worked with Ontario IESO on market design issues, with the Ontario Ministry of Energy on the Clean Energy Supply RFP and with OPA on a variety of advisory assignments. NERA was instrumental in developing the standard form CES used by the OPA. Additionally, NERA has advised parties in TCPL's recent rate case and is familiar with the costs of gas transportation within Ontario. Since its founding in 1961, the economics of energy and particularly electricity have formed a significant part of NERA's practice. NERA's energy clients include American Electric Power, Public Service Electric and Gas Company, the Alberta Utilities Board, the New Brunswick Ministry of Finance, the New York Independent System Operator, the Illinois Power Agency and the Republic of Ireland Commission for Energy Regulation.

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Tab 3

ONTARIO POWER AUTHORITY

Cost of Relocating the Oakville Generating Station to Napanee

Background

In October 2010, the Ontario government announced TransCanada Energy's 900-megawatt Oakville Generating Station would not proceed. In December 2012, the Ontario Power Authority and TransCanada signed a contract that relocated the plant to Ontario Power Generation's site in Napanee.

In March 2013, the OPA retained NERA Economic Consulting to review and provide an independent, expert calculation of the costs for relocating the Oakville plant to Napanee.

Findings

NERA determined that the cost of relocating the Oakville Generating Station to Napanee is $241 million.

NERA arrived at this number by first calculating the timing of payments and costs that would have resulted under the contract if the plant had gone ahead in Oakville. The assumption was made that the plant would have been in-service in March 2014 as set out in the Oakville contract.

NERA then identified the categories of costs that changed as a result of the relocating the plant to Napanee:

- Savings associated with reduced monthly contract payment - $670 million
- Cost of upfront turbine payment and sunk costs - $250 million
- Cost of gas delivery and management - $350 million
- Cost of transmission and gas connections - $42 million
- Cost of transmission line losses - $24 million
- Cost of advancing replacement transmission - $88 million
- Cost of additional capacity required before Napanee up and running - $153 million

Once NERA had calculated the timing of payments and costs for both the Napanee and Oakville plants both costs were converted to a net present value using a social discount rate of 6 percent so the costs could be compared:

- Cost of Napanee $2.33 billion
- Cost of Oakville $2.10 billion
- Cost of Relocation $241 million

NERA

NERA Economic Consulting is recognized as one of the world's leading international economic and financial consulting firms. Energy economics, and particularly electricity, make up a significant part of NERA's work. NERA has provided OPA with expert advice on procurement and other issues and has also done work for the Independent Electricity System Operator (IESO) and the Ontario Ministry of Energy.

April 30, 2013

Tab 4

Estimated Oakville GS Relocation Costs - 29 April 2013

(Please refer to the accompanying explanatory notes.)

Payments Made to TransCanada		**Comments**
Gas Turbine Cost	$210	Cost of the gas turbines for OGS that are re-purposed in Napanee - noted as $210M in MOU
Oakville GS Sunk Costs	$40	Costs to develop the site in Oakville - capped at $40M in MOU. Noted as sunk costs in backgrounder.
	$250	
Future Site-related Costs		
Transmission Connection	$37	Estimated cost to connect to the transmission system in Napanee - noted as $ TBD in MOU pending final design
Gas Connection	$10	Estimated cost to connect to the gas pipeline in Napanee - noted as $ TBD in MOU pending final design
Land and Site Services	$0	OPA to pay if total costs exceeds $18.25M but capped at $5M - noted in the contract.
Gas Delivery & Management	$406	Estimated costs associated with delivering gas to Napanee and managing it - noted in MOU
	$453	
Future System-related Costs		
Bulk Transmission Upgrade in SWGTA	$90	Estimated system costs associated with moving certain transmission projects ahead 10 years to 2018. Flagged in 2010 announcement and LTEP. Originally estimated at $200M in disclosed OPA slide deck.
Higher Line Losses	$32	Estimated electricity losses caused by having generation located far from the loads it serves and disclosed in OPA slide deck and included in $200M.
Lower Turbine Efficiency	$53	Napanee GS has a lower efficiency than OGS because of the fast start capability, but there is value in having this capability.
	$176	
Contract-Related Savings		
Savings from Reduced Monthly Payments for Napanee	($195)	Savings from reducing the NRR from $17,277/MW-month to $15,200/MW-month, which is set out in the MOU.
Savings and Cost Estimates Contingent on Assumptions		
Savings from Time Deferral of Payments from 2014 to 2019	*($539)*	Savings from starting payments later. This assumes that the contracted Commercial Operation Date (COD) for OGS (February 2014) would have occurred. If later COD is assumed then the savings are reduced, but the estimated cost of replacment power may also be reduced.
Cost of Replacement Power Services in 2017 and 2018	*$215*	Estimated additional resources needed in 2017 and 2018.
Savings Because Napanee will be in service for 5 years after Oakville	*($50)*	Estimated value of replacement power not required after the SWGTA Contract would have expired in 2034.
Future Potential Savings	*($374)*	
Relocation Cost (Saving)	***$310***	

Notes:

All estimates are in 2013 $.

Nominal social discount rate of 6.08% (4% real social discount rate and 2% inflation).

OGS is assumed to have achieved Commercial Operation on February 8, 2014 and Napanee GS is assumed to have achieved Commercial Operation on December 31, 2018.

The analysis period is 2014 to 2038 to provide a common time horizon for the discounted cash flow analysis.

GD&M costs for Napanee GS are estimated to be $3,400/MW-month.

Additional capacity needs to be acquired in 2017 and 2018 prior to Napanee GS coming into service.

Tab 5

ONTARIO POWER AUTHORITY

EXPLANATORY NOTES
Estimated Costs of Relocating the Oakville Generating Station to Napanee

There are both costs and savings associated with relocating the Oakville Generating Station to Napanee. Both need to be taken into account when calculating the total costs of relocation. The costs and savings detailed below in many instances are estimates based on the information known at this time as well as assumptions about future elements (e.g. gas prices, electricity demand). These costs and savings will evolve over time as detailed engineering work is performed and information becomes available.

Payments Made to TransCanada

Upfront payments to TransCanada were validated and approved by an independent engineer.

Gas Turbine Cost

TransCanada ordered and paid for the Oakville gas turbines because of the long lead time required to manufacture them. These turbines will be used in Napanee. Recognizing that TransCanada would be carrying these costs beyond what they had planned due to the cancellation of the Oakville contract, the OPA agreed to pay for the turbines upfront rather than through the monthly contract payment that TransCanada will receive once the plant is up and running. **The cost of the upfront turbine payment is $210 million and was offset by a lower contract payment or net revenue requirement (NRR).**

Oakville GS Sunk Costs

Sunk costs are the costs for goods and services TransCanada incurred in Oakville that cannot be used in Napanee and include things like land, engineering and design work, permitting, employee costs and overhead. **The sunk costs associated with the Oakville Generating Station are $40 million**.

Future Site-related Costs

Transmission Connection

There are costs associated with connecting the power plant to the bulk transmission system. In Oakville the plant would have connected to a 230-kv line. At the Napanee site, the plant will connect to a 500-kV line, which will cost more. The OPA is covering this cost because it was part of the negotiated settlement as reflected in the MOU. **The cost to connect the Napanee Generating Station to the transmission system is estimated to be $37 million.**

Gas Connection

There are costs associated with connecting the power plant to the gas supply. The OPA is covering these costs because it was part of the negotiated settlement as reflected in the MOU. **The gas connection costs are estimated to be $10 million.**

Land and Site Services

The Napanee contract has a provision that would see the OPA covering any land and site services costs that exceed $18.25 million up to a maximum of $5 million. **The OPA estimates that these costs will not exceed $18.25 million and therefore will add $0 to the total cost of relocation.**

Gas Delivery & Management

Gas delivery and management (GD & M) are costs associated with transporting natural gas from the Dawn gas hub near Sarnia and managing it on the Napanee site. Napanee is further from the Dawn hub than Oakville, therefore these costs will be higher. The OPA agreed in the MOU to cover the GD & M but also reduced TransCanada's monthly contract payment equivalent to what TransCanada would have been paid for GD &M in Oakville. **The OPA estimates the gas delivery and management costs to be $406 million, which is offset in part by a lower contract payment.**

Future System Costs

Bulk Transmission Upgrade in SWGTA

SWGTA needs additional electricity in the short and long term. Conservation and slower growth because of the 2008 recession changed the timing of the need in the short term from 2014 to 2019. When the government made the decision not to proceed with the Oakville Generating Station, the transmission upgrades that had been planned to be built for 2029 to meet long-term needs had to be advanced to 2019. **The estimated net cost of building transmission 10 years earlier as a replacement for the Oakville Generating Station is estimated to be $90 million**.

Line Losses

The power generated at the Napanee Generating Station will be consumed in other parts of the province where the demand is. Transmitting electricity over long distances results in some power being lost during transmission. **The estimated costs associated with line losses are estimated to be $32 million.**

Turbine Efficiency

In 2011, TransCanada had the turbines upgraded to have fast-start capability because at the time it was thought TransCanada would develop a peaker plant in Cambridge that required fast starts. The fast-start capability has potential value to the system but once operating, the turbines are not as efficient as they would have been in Oakville without this capability. The value associated with this capability has not been estimated at this time. **The costs associated with the operation of the fast-start turbines are estimated to be $53 million.**

Contract Related Savings

Reduced Monthly Payments

The net revenue requirement (NRR) is the monthly contract payment the OPA pays a power plant developer. A power plant developer does not receive these payments until the power plant is up and running. The NRR then covers the capital and operating costs and provides a rate of return that is dependent on how efficiently the developer builds and operates the plant. The Oakville NRR was $17,277/MW-month. The Napanee NRR is $15,200 MW-month. The reduction was made to offset the upfront turbine payment and a portion of the gas management and delivery costs. **The estimated savings associated with the reduced NRR are $195 million.**

Savings and Cost Estimates Contingent on Assumptions

Cost of Replacement Capacity in 2017-2018

In addition to meeting local reliability needs, the Oakville Generating Station, which was to be in service in 2014, would have provided generating capacity at the provincial level. Replacement capacity could therefore be required in 2017/2018 when nuclear refurbishments start and before the Napanee Generating Station is up and running in 2018. **The estimated cost of this replacement capacity is $215 million.**

Savings from Napanee being in Service Five Years after Oakville

This is the estimated value of having the Napanee Generating Station under contract for five years after the Oakville Generating Station contract would have ended. **The savings are estimated to be $50 million.**

Savings from Time Deferral of Payments from 2014 to 2019

Under the original Oakville contract, TransCanada was required to have the plant up and running by 2014. The Napanee Generating Station is slated to be in service on December 31, 2018. Starting payments later results in savings over the 20 year period of the contract because of the time value of money. This savings estimate assumes that the contracted Commercial Operation Date ("COD") for OGS (February 2014) would have occurred. If a later COD is assumed then the savings are reduced, but the estimated cost of replacement power may also be reduced. **The savings associated with deferring the contract payments are estimated to be $539 million.**

Tab 6

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

March 18, 2013

Shafiq Qaadri
Chair of the Standing Committee on Justice Policy
Ministry of Government Services
Room 4320, 4th Floor, Whitney Block
99 Wellesley Street West
Toronto ON M7A 1W3

Dear Mr Qaadri:

RE: Standing Committee on Justice Policy

I am writing on behalf of the Ontario Power Authority (the "OPA") to raise matters regarding the hearings of the Standing Committee on Justice Policy into the cancellation of two gas plants in Ontario.

All of us at the OPA respect the Committee's work and intend to cooperate fully as it studies the issues before it. In anticipation of the appearance of OPA witnesses before the Justice Committee, we wish to suggest a protocol for the handling of documentary and other evidence, particularly evidence outside of the May 16, 2012 Estimates Committee motion, that raise issues of privilege and confidential commercial information.

The issue of the handling of privileged and confidential information was raised by the Committee's questions to former Speaker Peter Milliken, who appeared before you previously. One possible solution that we would suggest is to have privileged or confidential matters be addressed in-camera so that the Committee can do its work but without the public disclosure of such information.

We raise these matters out of concern for the public interest. Our concern is that if privileged and confidential information is disclosed publicly, Ontario will face difficulties in its dealings with investors and counterparties, current and future, who will not be willing to participate in competitive tenders if there is a risk that proprietary information will be released publicly in a Committee process.

We also submit that there is a need for a protocol regarding information that relates to other projects or activities, or concerns personal information that has been redacted from the correspondence disclosed by the OPA. We would propose a third party such as a staff member or solicitor, or a confidential subcommittee of the Committee could be asked to verify that the redactions are appropriate. While the Committee should satisfy itself that the redactions are proper, we would similarly ask that it do so without revealing that information to the public. In that way, information of third parties unconnected to this issue will be protected.

We also want to confirm that the disclosure of the information the Committee seeks does not constitute a waiver of privilege or confidential commercial information over the documents outside of the proceedings of the Legislative Assembly and its Committees.

The OPA looks forward to assisting the Committee in this important work and I would be pleased to discuss this issue further.

Yours very truly,

Colin Andersen
Chief Executive Officer

cc Tamara Pomanski – Clerk of the Standing Committee on Justice Policy

Tab 7

ONTARIO POWER AUTHORITY

120 Adelaide Street West
Suite 1600
Toronto, Ontario M5H 1T1

T 416-967-7474
F 416-967-1947
www.powerauthority.on.ca

April 9, 2013

Tamara Pomanski
Clerk
Standing Committee on Justice Policy
Room 1405, Whitney Block
99 Wellesley Street West
Toronto M7A 1A2

Dear Ms Pomanski:

I would like to take this opportunity to clarify some remarks made during my testimony before the Standing Committee on Justice Policy on March 19, 2013.

First, I want to elaborate on my answers to questions from Kevin Flynn on the OPA's procurement process and the scoring system used within it for the Oakville Generating Station. I have attached a document that outlines the criteria and how the process worked.

As I indicated in my testimony, it is mathematically possible that a project not as advanced in the rated criteria (with, however, a minimum of 40 points) and with a lower price could win out over a project more advanced in the rated criteria (i.e. with a higher number of points) and with a higher price.

The evaluation team for the Southwest GTA procurement, which led to the Oakville Generating station contract, consisted of five people - two from the OPA, one from the Ontario Energy Board (OEB), one from the Independent System Operator (IESO) and an independent consultant retained by the OPA who acted as chair. The team was overseen by a Fairness Advisor provided by a consulting company selected through a competitive procurement. The contract data were taken directly from the developer bids and run through a financial model, which was also on our website. The final overall lowest adjusted evaluated cost determined the winning project. It is a process with no intervention by anyone, except for analysis from the evaluation team based in part on mathematical outputs and the advice of the fairness advisor.

Second, I was asked a question by Peter Tabuns about gas demand and management (GD&M) charges for the Napanee Generating Station. In reply, I indicated that our Net Present Value (NPV) estimate is between \$319 million and \$476 million. Since then, this range of numbers and the \$40 million in sunk costs have been used to calculate a total relocation cost of more than \$800 M and attributed to me.

I did not speak to the total costs of relocation during my testimony. The GD&M costs and sunk costs are just two costs associated with the Napanee Generating Station. Other costs and savings need to be accounted for in order to have an accurate number for the total costs of relocation. Detailed design and engineering work needs to be complete before some of these costs can be accurately quantified. There are also savings from starting the contract payments later than they would have been in Oakville and these too need to be calculated.

Thank you for considering my follow-up on these two matters.

Regards,

JoAnne Butler
Vice President Electricity Resources
Ontario Power Authority

Southwest GTA Procurement Evaluation Criteria Summary – Mar 15 2013

Stage 1: Completeness

Stage 2: Mandatory Requirements

- **Location**
    - Etobicoke, Mississauga, or Oakville
    - Not on any portion of retired Lakeview facility
- **Control of Site and Private Connection Line**
    - Site Control - ownership, option to purchase, option to lease, option to license, etc.
    - Private Connection Line - control for portions not controlled by public entities
- **Connection Point and Line Distance**
    - Specified circuits to connect
    - Connection line distance of 2 km or less, does not require “leave to construct”
- Facility
    - New Build or Expansion, Single facility, Dispatchable, use pipeline natural gas, minimum ramp rate
    - CCGT facility (CHP components are optional), Comply with IESO generator connection requirements
- Fuel Supply (services from Union or Enbridge, not operate your own pipeline)
- Emissions
    - All requirements in Environmental Protection Act and accompanying regulations
    - In addition the following requirements more stringent than existing legislation
        - Nitrogen Oxides (NOx) <= 15 ppmv
        - Carbon Monoxide (CO) <= 15 ppmv
- Contract Capacity and Nameplate MVA Rating
    - No more than 900 MW in each season, no less than 750 MW in Season 3, specified MVA limits
    - Configuration requirements for units being out of service
- Milestone Date (achieve COD before December 31, 2013)
- Registered Participant or Control Group Member
- Development Experience (Company and Team Members)
- Tangible Net Worth
- Proposal security: $1 Million
- Economic Bid Statement

Stage 3: Rated Criteria

- Environmental Assessment – 20
- Municipal and Regional Approvals – 20
- Community Outreach – 20
- EPC Arrangements – 20
- Equipment Availability – 15
- Fuel Supply – 5

Maximum Point Score: 100 Minimum Required Point Score: 40

Stage 4: Economic Bid Evaluation and Selection

1. Calculation of the Evaluated Cost
2. Determination of any Outlier Proposals
3. Calculation of the Adjusted Evaluated Cost (factors in discount based on rating score)
4. Selection of Proposal with Lowest Adjusted Evaluated Cost

Tab 8

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July 7, 2010

Alternatives for Southwest GTA

Prepared by: Power System Planning

Scope of this presentation

- Rationale for Southwest GTA when planned in 2007
- Changes since 2007
- Alternatives for replacement
  - Transmission aspects
  - Generation aspects
- Preliminary results of analysis

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Rationale for building gas-fired generation in Southwest GTA

1. Replace coal

2. Complement wind

By placing generation in Southwest GTA:

3. Restore Supply-Demand balance for GTA

4. Relieve constrained transmission
    - *Auto-transformer at Claireville TS*
    - *Auto-transformer at Trafalgar TS*
    - *Richview-Manby transmission corridor*
    - *Reduce transmission losses*

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What has changed since 2007

- **Recession has reduced demand forecast, but not in GTA**
  - *Current demand projection is 1,100 MW lower by 2015*
  - *GTA load forecast is less affected*

- **Supply picture has changed:**
  - FIT program increases the amount of renewable generation
  - Less gas-fired generation planned
  - Prospect of Pickering continued operation
  - Uncertainty about Bruce refurbishment schedule

- **Delays in approvals process for Oakville GS**

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The effect of changes since 2007 on drivers for the plant

Factors shaping requirement for Oakville Generating Station	Current relevance in view of changes since 2007	Comments
Replace coal	Less relevant	Delays in OGS approvals will delay OGS in-service to beyond 2014: outside of the coal replacement timeframe
Complement wind	More relevant	FIT program will result more renewables, increasing requirement for flexible supply sources within Ontario's mix
Restore Supply-Demand Balance for GTA	Same	Demand in GTA continues to be robust. Need for transmission reinforcement starts in 2018
Relieve constrained transmission		

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OPA has been asked to evaluate three alternatives to the current Oakville GS

1. GTA transmission expansion and Nanticoke generation

2. GTA transmission expansion and Halton Hills GS expansion

3. Relocate Oakville GS to north Oakville and connect by transmission lines to Oakville TS

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Option 1: GTA transmission and Nanticoke generation

Extensive new transmission in GTA costing $200M :

- Claireville TS auto-transformer relief
  - 7km new transmission lines to Richmond Hill #1 & #2
  - $65M (overhead and underground)
- Trafalgar TS auto-transformer relief
  - New Auto-transformers at Milton SS and lines to Halton Hills TS
  - $90M to $105M (station and overhead)
- Richview to Manby Corridor relief
  - $20M - $30M (TxO or RxM)
    - 7km, $20M for Trafalgar x Oakville
    - 6.5km, $30M for Richview x Manby
- Increased transmission losses

Generation sites available, OPG facilities can be repowered but Gas pipeline has to be extended to Nanticoke: $150 Million, three years or more

Option 2: GTA transmission and Halton Hills GS expansion

- **Existing generating site can accommodate added units, but it is in a busy transmission corridor, inadequate to incorporate significant amounts of new generation without major transmission**
- **Requires comparable amount and cost of transmission to option one**

- 12 km new transmission line required from Halton Hills GS to Trafalgar TS to allow for expanded generation (est. cost: $40M)

- This option adds generation to the GTA and thus partially restores GTA supply/demand balance
  - but may only provide partial relief to Claireville TS and Trafalgar TS

Option 3: North Oakville generation connected by 7 Km transmission to Oakville south

- **Limited transmission needed: only 7 Km to the south on an existing right of way designated for transmission, preserves corridors shown for option 1 within GTA for future use**
- **$20M cost of new transmission if it is built as overhead transmission, $100M-$150M if underground**

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Results of assessment

- All alternatives must start with transmission into SW GTA

- Relocating to North Oakville and connecting with 7 Km transmission to Oakville TS achieves best results

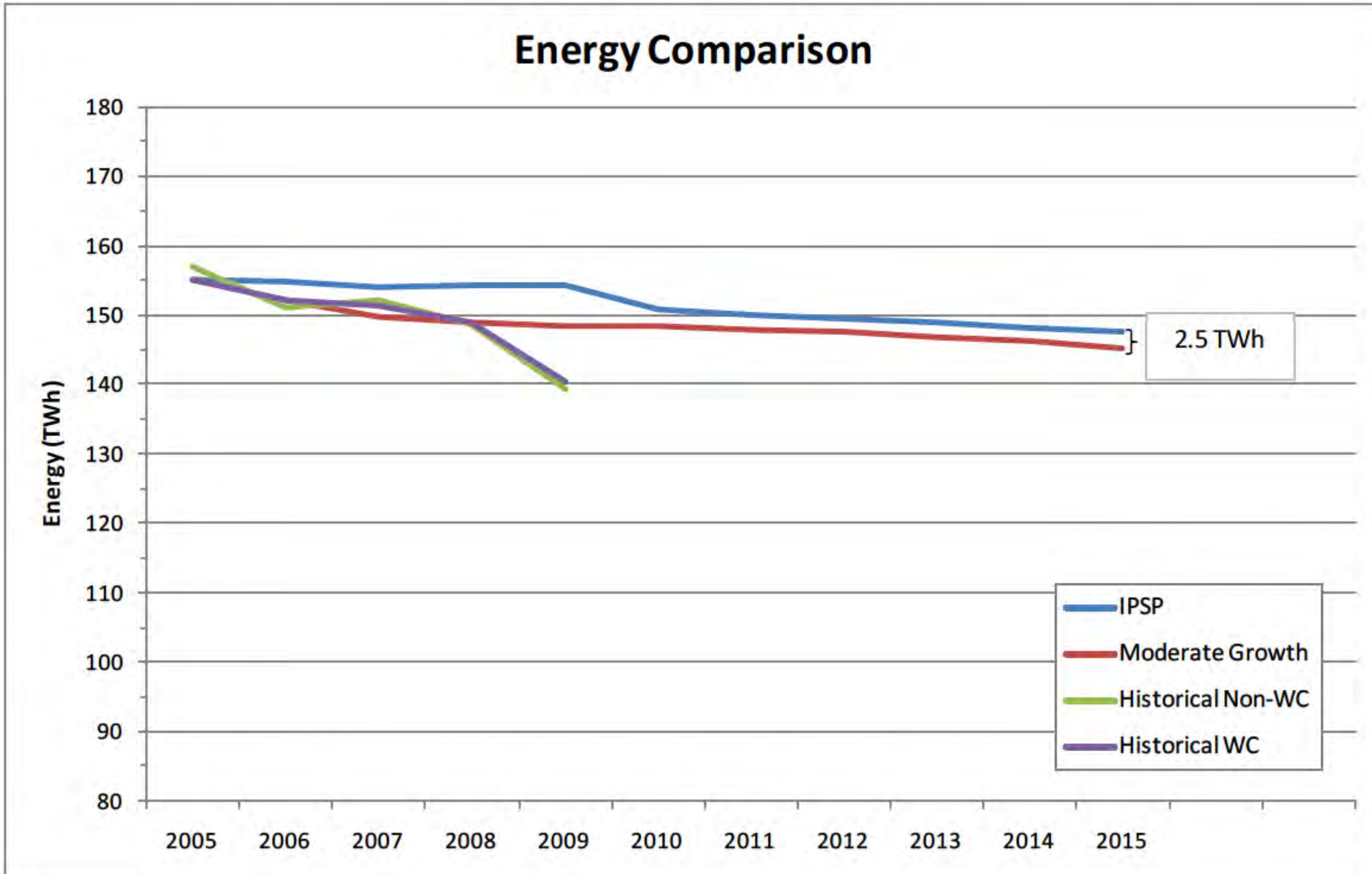
- Place higher priority on operational flexibility and transmission relief
  - Build Simple cycle gas turbines not combined cycle (because they can better complement wind)
  - Size to relieve transmission (starting around 2018). Smaller size is possible, around 350-500 MW It can be the first stage of an ultimate combined cycle plant of 850 MW
  - In service date can be delayed from original 2013 date to 2015. If 2015 in-service is not feasible, then other generation options will have to be activated.

APPENDICES

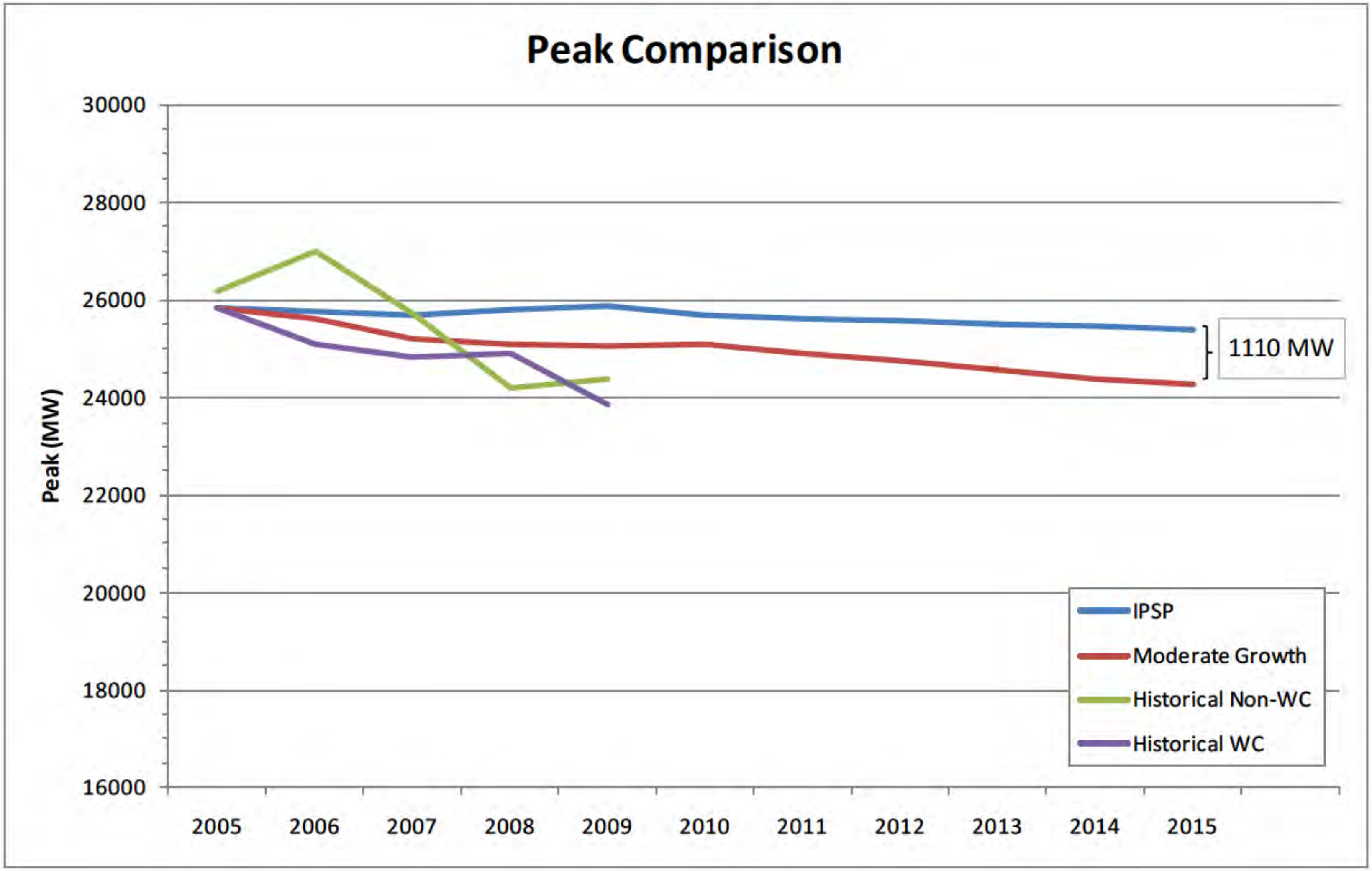
Contents:

ONTARIO POWER AUTHORITY

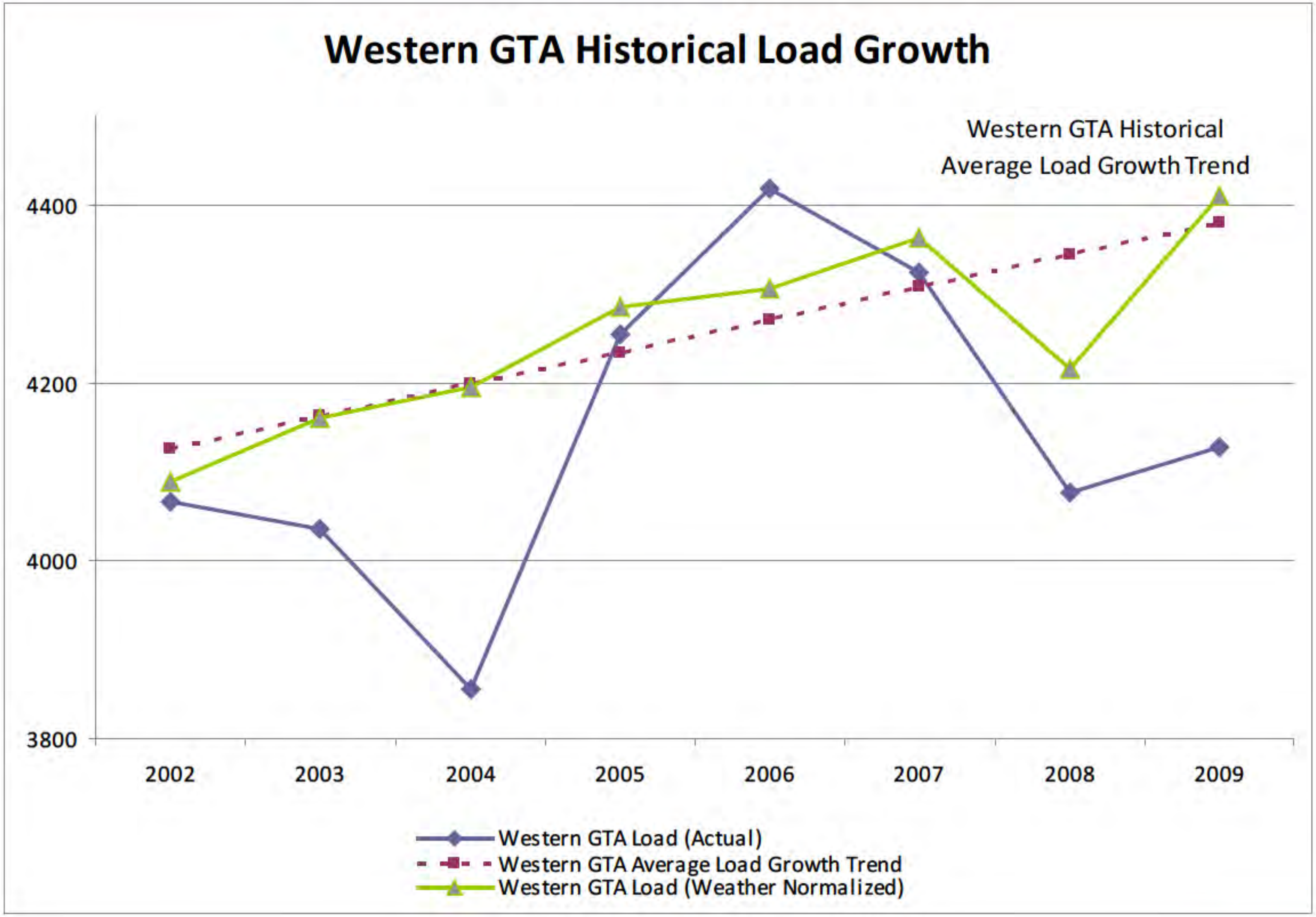
Appendix A:
Energy demand forecast is now 2.5 TWh lower than forecast made in 2007



Appendix A:
Peak demand forecast for 2015 is now 1110 MW lower than forecast made in 2007



Appendix A:
Demand is robust in western GTA



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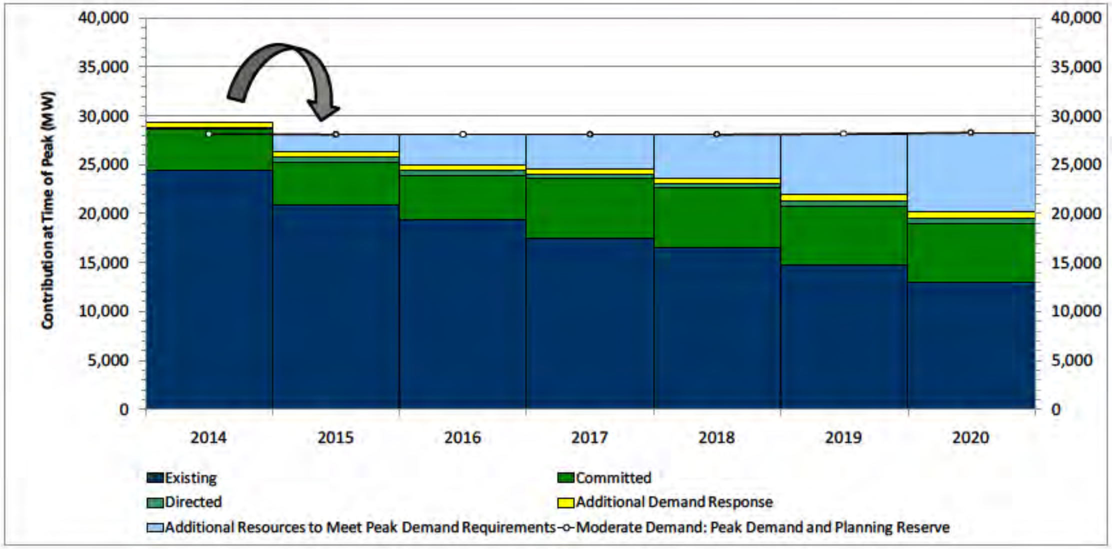
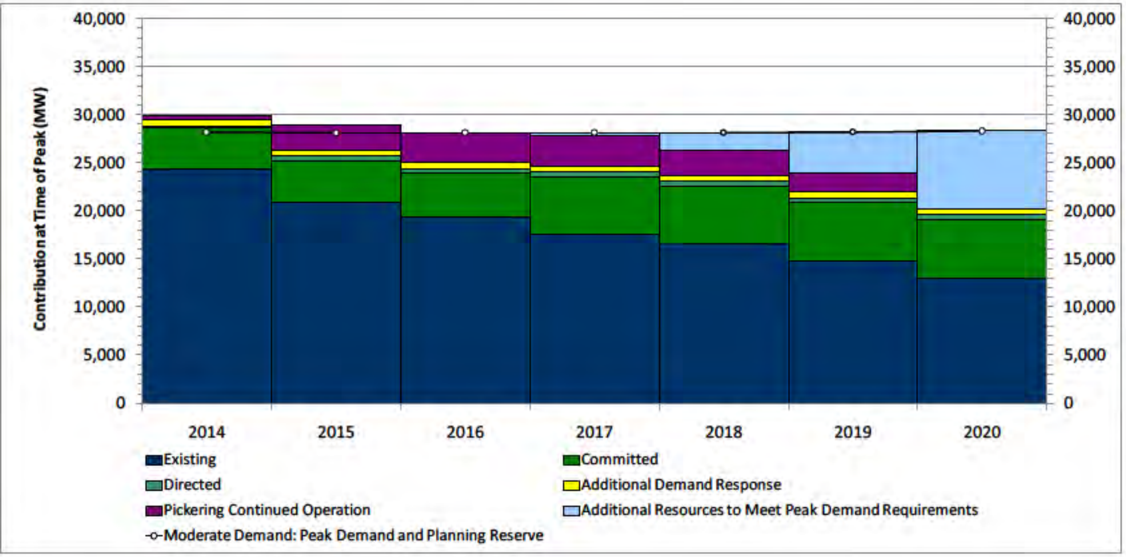
Appendix B:
Supply gap without Southwest GTA starts in 2015



Without Pickering Continued Operation

- 1,760 MW gap starts in 2015 and grows
- *Reduction in supply between 2014 and 2015 is mostly due to Pickering end of life (4 units, 2062 MW) and coal closure (4 units, 1286 MW)*



With Pickering Continued Operation

- Gap starts around 2018

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Appendix B:
Supply outlook by project in the year 2015 (Installed MW)

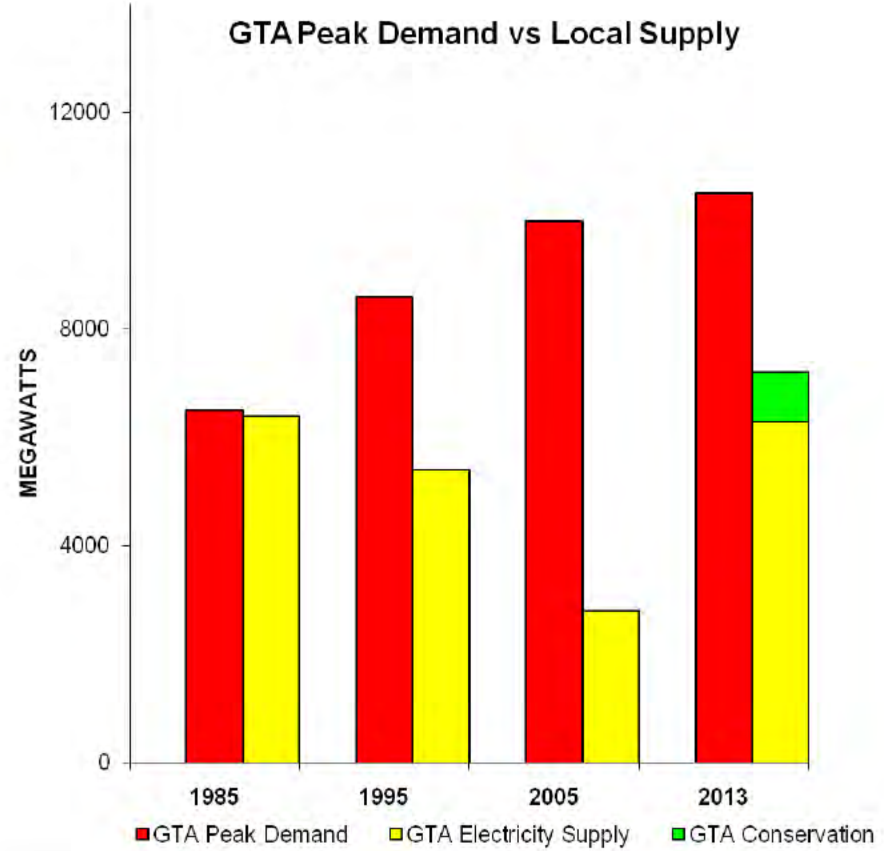
Status	Resource Type	Commitment	Project	Installed MW
Existing	Nuclear	Bruce	Bruce Units 5 - 8	3,288
		Darlington	Darlington Units 1 - 4	3,524
		Pickering	Pickering Unit 8	516
		CTU	Various	45
	Gas	Accelerated Clean Energy Supply	Portlands Energy Centre	639
			Goreway Station	942
		Clean Energy Supply	Greater Toronto Airports Authority	117
			Greenfield Energy Centre	1,153
			St. Clair Energy Centre	678
		Combined Heat and Power 1	East Windsor Cogen	100
			Thorold Cogeneration	287
			Warden Energy Centre	5
			Durham College District Energy	3
			Great Northern Tri-gen	11
			Countryside London Cogen	12
		Early Movers Clean Energy Supply	Brighton Beach	580
			Sarnia	510
		Lennox	Lennox	2,105
		Non-Utility Generator	Various	926
		Dow Chemical	Dow Chemical	100
		CTU	Various	13
	Renewables	Combined Heat and Power 1	Algoma Energy	63
		Hydroelectric Contract Initiative	Various	983
		Hydroelectric Energy Supply Agreement	Ear Falls	17
			Lac Seul	13
		Renewable Energy Supply 1	Glen Miller/Sidney (Hydro)	8
			Eastview Landfill Gas	3
			Melancthon 1 (Wind)	68
			Kingsbridge 1 (Wind)	40
			Erie Shores (Wind)	99
			Hamilton Community Digester	2
			Trail Road Landfill Gas	5
			Prince Wind Power Project 1	99
			Umbata Falls	24
		Renewable Energy Supply 2	Prince Wind Power Project 2	90
			Ripley Wind Farm	76
			Melancthon 2 (Wind)	132
			Kruger Energy Port Alma Wind Power Project	101
			Enbridge Ontario Wind Farm	182
			Wolfe Island Wind Project	198
		Renewable Energy Standard Offer Program	Various	214
		Hydroelectric	Various	6,874
		Biomass	Various	113
		Other Small Resources	Various	4
	Demand Response	Various Demand Response Programs	Various	140

Status	Resource Type	Commitment	Project	Installed MW
Committed	Nuclear	Refurbishment	Bruce A Units 1 & 2	1,500
	Gas	Clean Energy Supply	Greenfield South	280
			Oakville	900
		Accelerated Clean Energy Supply	Halton Hills	632
		Peaking Generation Contract	York Energy Centre	393
	Renewable	Hydroelectric Energy Supply Agreement	Upper Mattagami	61
		Renewable Energy Standard Offer Program	Various	805
		Renewable Energy Supply 2 & 3	Island Falls	20
			Kruger Wind	101
			Gosfield Wind	50
			Raleigh Wind	78
			Talbot Wind	99
			Greenwich Wind	99
		Combined Heat and Power 3	Becker	15
		Feed-in-Tariff Program, including microFIT	Various	2,805
		Korean Consortium	Phases 1, 2 & 3	1,500
	Demand Response	Various Demand Response Programs	Various	346
Directed	Renewable	Hydroelectric Energy Supply Agreement	Lower Mattagami	450
		Atikokan Biomass Energy Supply Agreement	Atikokan	200
Pickering Continued Operation	Nuclear	Pickering Continued Operation	Pickering Unit 1-7	2,578
Additional Demand Response	Demand Response	Various Demand Response Programs	Various	648
			Total	38,660

Appendix C:
Supply-Demand balance in GTA

New GTA supply from 2005 to 2013:

- Goreway GS – 860 MW (2009)
- Portlands Energy Center – 550 MW (2009)
- Halton Hills GS – 600 MW (2010)
- Northern York Region – 350 MW (2011)
- Greenfield South – 280 MW (2012)
- Oakville GS – 900 MW (2014)



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Appendix C:
Western GTA – constrained transmission

- **Key Stations**
  - Claireville TS
  - Richview TS
  - Manby TS
  - Oakville TS
  - Parkway TS
  - Trafalgar TS

- **Constrained transmission**
  - Richview x Manby corridor
  - Transformers at Claireville TS
  - Capacity at Trafalgar TS

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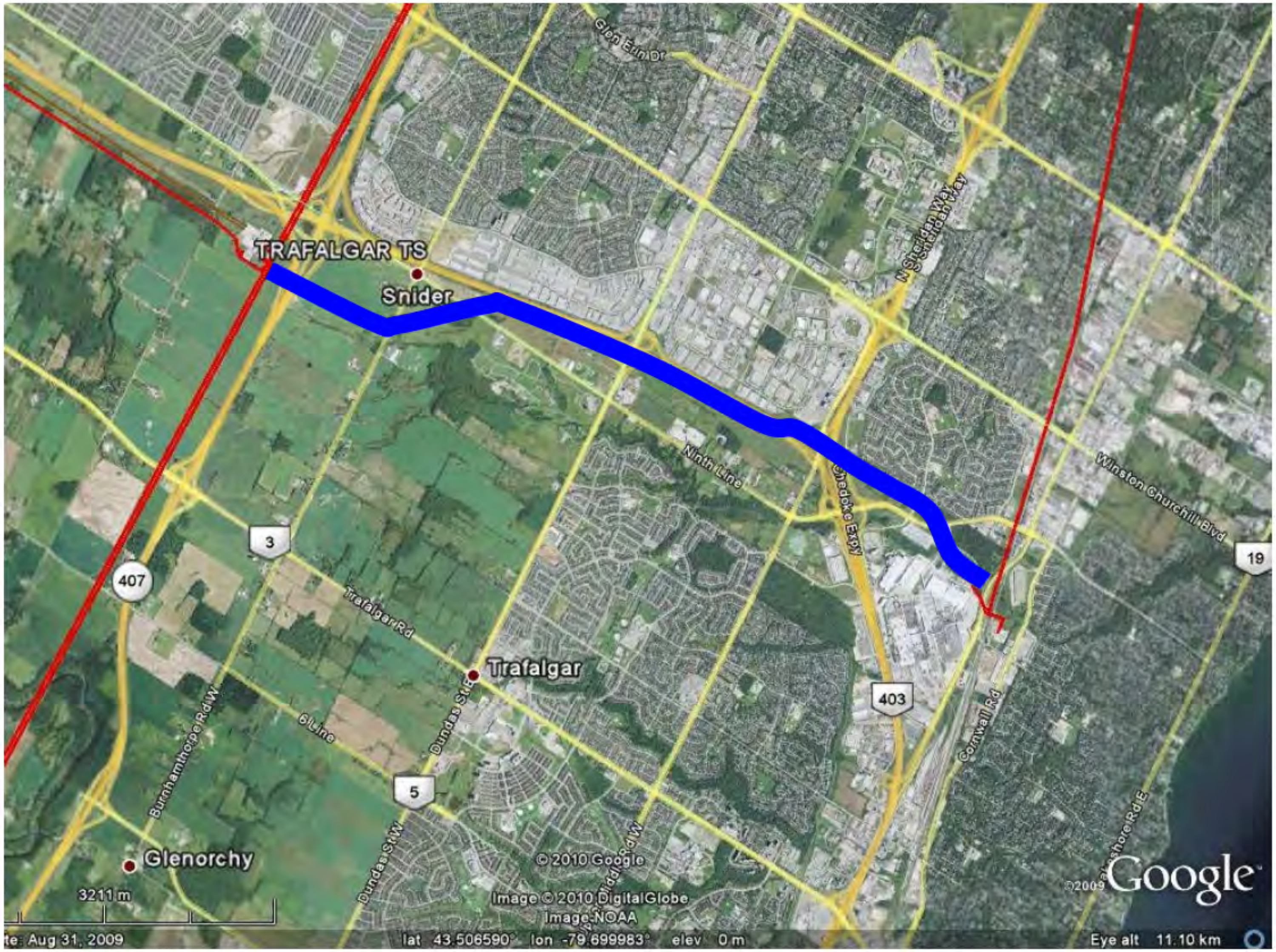
Appendix D:
Transmission corridor information for option three

- Parkway Belt West Plan was implemented by the Province of Ontario in 1978 “for the purposes of creating a multi-purpose utility corridor, urban separator and linked open space system”
- Land corridor is available for transmission, but has no transmission towers on it. Previous attempts to build transmission overhead met with local objections
- Exemption Order OHK-11 under the Environmental Assessment Act provides for certain Transmission ROWs within the Parkway Belt, including Trafalgar TS x Oakville TS, to be exempt from EA requirements

Appendix D:
Approximate Trafalgar x Oakville Right of Way



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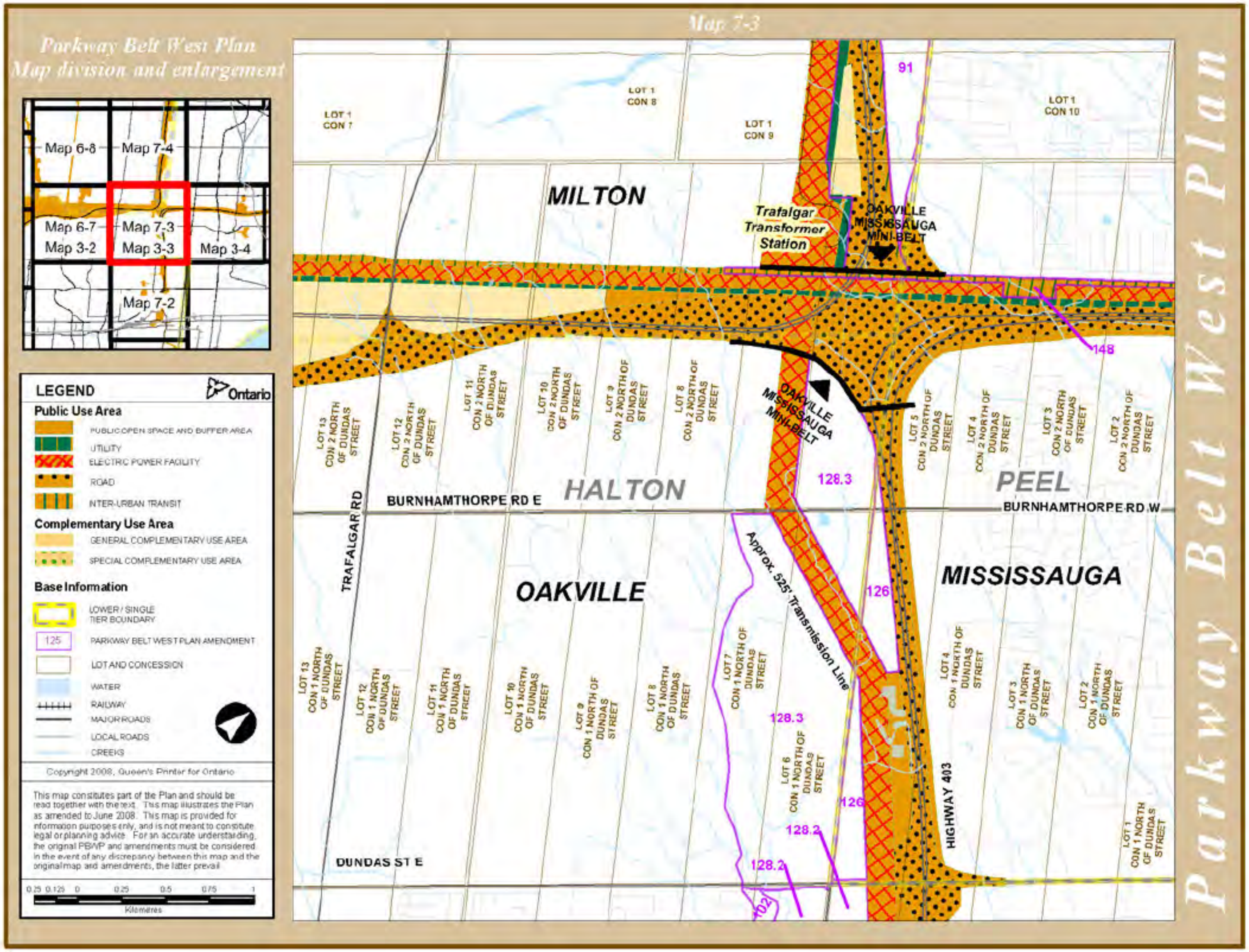
Appendix D:
North Trafalgar to Oakville TS



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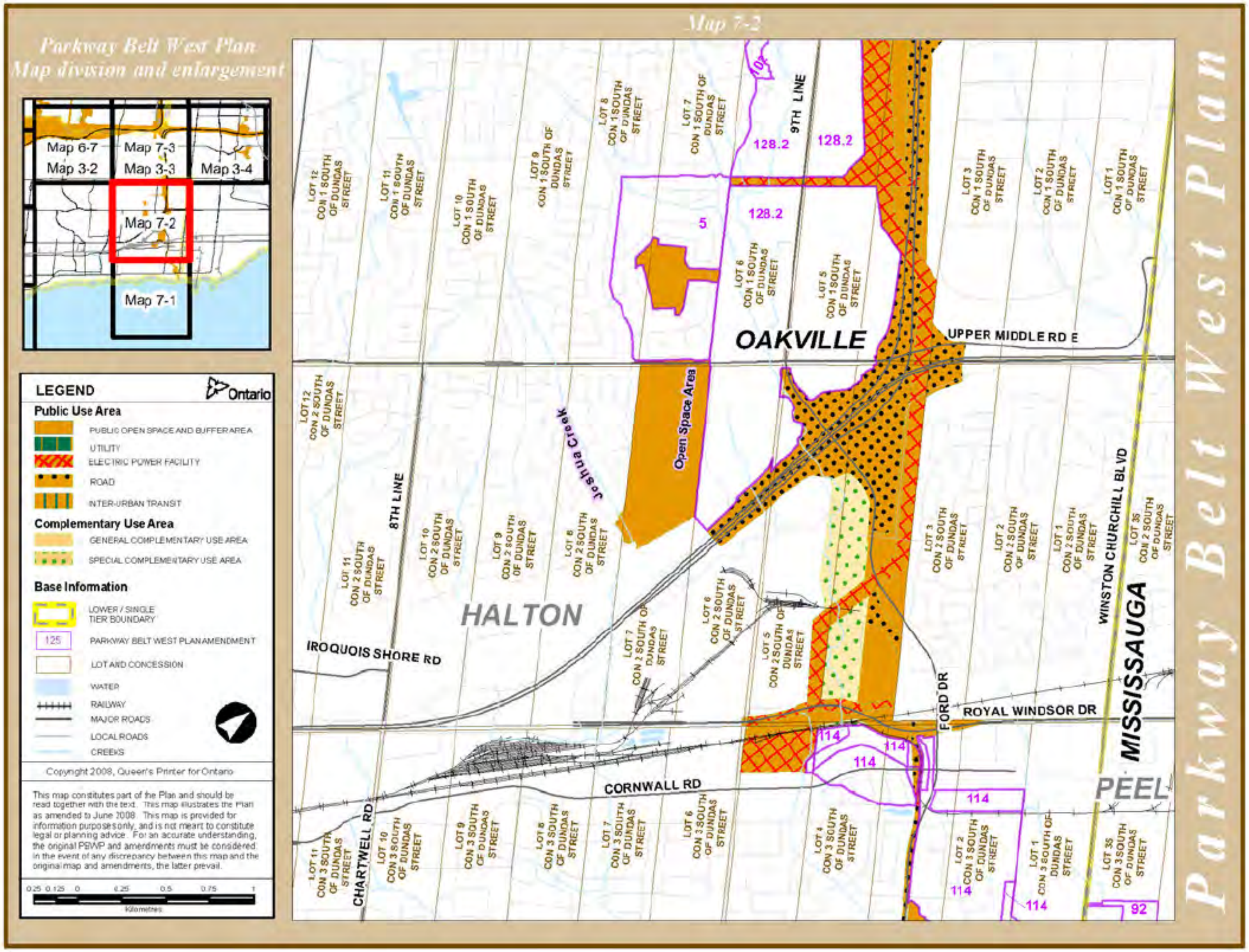
Appendix D:
South Trafalgar to Oakville TS



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Tab 9

Coulter A. Osborne

April 19, 2013

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
120 Adelaide Street West, Suite 1600
Toronto, ON M5H 1T1

Dear Mr. Andersen,

Through your counsel and directly you have asked me to comment on several aspects of orders issued by duly constituted committees of the Ontario legislature for the production of documents pertaining to the cancellation of two contracts for the construction of power plants, one in Mississauga and the other in Oakville.

During our meeting you also asked me to provide in this letter the salient features of my background. I can confirm that I was called to the Ontario Bar in 1959. I practiced in Kitchener as a litigator from 1959 until my appointment to the Supreme Court of Ontario, High Court of Justice in 1978. In 1990 I was appointed to the Court of Appeal for Ontario until my retirement from the court in 2001. In 1999 I was appointed Associate Chief Justice of Ontario. Between 1999 and 2001 I was Chair of the Ontario Civil Rules Committee. Following my retirement from the court I was appointed as the Integrity Commissioner for the Province of Ontario. In that capacity I was an Officer of the Legislature. In 2007 I was asked to chair a review of the Civil Justice system. This review included consideration of issues related to the production and discovery of documents in litigated matters. More recently I have worked as a mediator and arbitrator, mainly in relation to commercial disputes.

For introductory purposes it will suffice to say that complying with the committees' production orders was somewhat challenging, given the turnaround time provided in those orders and the

333 Bay Street, Suite 900 Toronto ON M5H 2T4
Tel: 461-642-0274 Email: coulterosborne@mac.com

Ontario Power Authority's (OPA's) lack of experience and readiness for purposes of a response to document production requests. This lack of readiness is evidenced by the fact that the OPA had to acquire search software after the committees' production orders were issued. This additional software was felt necessary to enhance the OPA's capacity to respond to the document requests to which I have referred above. In addition, the OPA retained the services of PWC to provide guidance in matters that included a timely compliance with production orders such as those issued by the committees.

In the course of my life as a trial judge (and when I was on the Court of Appeal) I dealt with evidentiary issues having to do with the production and disclosure of documents. This included matters in which solicitor-client privilege, litigation privilege and the disclosure of commercially sensitive information were issues of concern. I have continued to deal, on occasion, with those issues as an arbitrator.

At the outset I accept and assume that two committees of the Legislative Assembly have and have exercised their power to compel the production of documents relative to the subject matter the committees' work. There is, therefore, no debate about the legitimacy of the committees' document production orders. The issue, as I see it, that remains is public disclosure of some of the documents ordered to be produced. This is an issue separate from the production by the Ministry of Energy and the OPA of documents relevant to the cancellation of the Mississauga and Oakville power plant contracts. Concerns about the disclosure of some, but certainly not all, of the produced documents lies in the law of evidence pertaining to solicitor and client privilege, litigation privilege and legal limitations placed on the disclosure of commercially sensitive information.

In the course of preparing this letter I have reviewed extensive Hansard references to production and disclosure of documents relevant to the cancellation of the Oakville and Mississauga power plant contracts. It is apparent that the focus of the legislature's concern was on the Ministry's and OPA's failure to make timely and complete production. Although solicitor and client privilege, litigation privilege and the disclosure of commercially sensitive documents were from

time to time referred to, it does not appear that the prospect of some remedial action was the subject matter of substantive discussion.

Some reference to the relevant chronology will be helpful in putting matters in context. For the most part I have taken this chronology from the ruling of the Speaker on September 13, 2013 (Hansard p. 3606). On May 16, 2012 the Standing Committee on Estimates adopted a motion requesting the Ministry of Energy and the OPA to provide documents within two weeks including correspondence relating to decisions made in 2010 and 2011 not to proceed with the construction of power plants in Oakville and Mississauga. On May 30, 2012 the Minister of Energy responded to the committees' request by indicating that it would not be appropriate to disclose the correspondence because some parts of the relevant files were confidential and others were subject to solicitor and client privilege or litigation privilege. The Minister's contention was that disclosure would tend to prejudice ongoing negotiations and litigation. The Speaker noted that the OPA responded in the same way. On June 5, 2012 the member from Cambridge called for a report from the committee to the House with respect to the Minister's May 30, 2012 decision not to provide the required documents. On August 27, 2012 the member from Cambridge rose on a question of privilege concerning the government's failure to produce documents to which I have referred above. These documents had been requested by the Standing Committee on Estimates. The member's question of privilege having been raised required the Speaker to consider and rule on the matter.

On July 11, 2012 the Minister provided some of the requested documents. He indicated that others would not be provided because they were subject to various legally recognized privileges. However, the timeliness of the document disclosure remained an issue as did what, if anything, to do about documents attracting solicitor and client or litigation privilege and documents containing commercially sensitive information.

Throughout the relevant timeframe, Members, the Minister of Energy, the Speaker, the Honourable Peter Milliken, former Speaker of the House of Commons, James McCarter, the provincial Auditor General and the former Secretary of the Cabinet all recognized the problem as related to the disclosure of material attracting solicitor and client privilege, litigation privilege

and commercially sensitive information. Indeed, on the matter of prejudice accruing from the disclosure of commercially sensitive information, the Auditor General in commenting on the disclosure of commercially sensitive information said somewhat rhetorically but I think correctly that "…in layman's language, it's like playing poker. You don't show the people around the table your cards." Mr. Milliken's personal experience as Speaker of the House of Commons did not include matters where solicitor and client or other privilege issues were raised except for national security interests which were implicated in the well-known Afghan detainee matter. Steps were taken in connection with that production issue to ensure that national security interests were not compromised in the document production process.

There are several solutions to the random disclosure of confidential or privileged information that would not dilute the committees' right to production of all relevant documents. I proffer these possible solutions as suggestions only since I recognize that it is for the Legislature to determine how to resolve the privilege/confidential information problem. One potential solution would involve a sub- committee having the mandate to review documents in which some degree of privilege or confidentiality (in relation to the government of Ontario or a third party) is claimed. A more efficient solution would be to retain someone who is, and is viewed to be, independent who would review documents raising privilege or confidentiality concerns. That person would rule on the privilege or confidentiality claims and exempt from public disclosure, but not production, those documents that are viewed to be privileged or confidential.

There are, of course, variations on this theme. The privilege/confidentiality adjudication could also be done by three persons, an option that could involve nominees from all three parties. I would hope that all nominees would have some knowledge and expertise in relation to privilege and confidentiality claims.

Whatever solution is employed, I think that it is in the public interest that there be some resolution of the privilege/confidentiality document problems. Although not controlled by the exemptions in the Freedom of Information Act, the committees' decisions as to what should be done about privilege and confidentiality issues should be informed by Freedom of Information Act values which include the exclusion of privileged and confidential documents from

production. In the circumstances that exist here all relevant documents would be produced but disclosure of those documents that are commercially sensitive or privileged would be subject to a form of review chosen by the Legislature. The process chosen could also be used to assess the propriety of redactions which I assume are based on relevance considerations.

Please let me know if anything further is required.

Yours very truly,

p.p. Coulter Osborne

Coulter A. Osborne

Tab 10

ONTARIO POWER AUTHORITY

Southwest GTA Procurement Process
Submission to Standing Committee on Justice Policy

March 19, 2013

Decision to Procure a Gas-Fired Power Plant in the Southwest GTA

- In its 2007 Integrated Power System Plan (IPSP), the OPA identified a provincial need for a new gas-fired power plant. The southwest GTA was a cost-effective area to locate the new plant because it was a high growth area and needed additional electricity. If a plant was located in the southwest GTA, transmission upgrades could be deferred.

- August 18, 2008, the Minister of Energy issued a directive to the OPA to procure a gas-fired power plant in the southwest GTA. August 20, 2008, the Minister of Energy sent a letter to the OPA stating that the Lakeview Generating Station was not going to be considered as a site for a new power plant in the southwest GTA.

Procurement Process

- The southwest GTA procurement process, including the contract with TransCanada, required power plant developers to comply with all regulations and laws with respect to safety, environmental protection and municipal approvals in place at that time in the province of Ontario.

- The OPA selected TransCanada's Oakville Generating Station through a two-staged, competitive procurement process. The OPA issued a request for qualification (RFQ) process in October 2008. In January 2009, the OPA released the results of the RFQ. Four power plant developers were qualified to participate in the request for proposal (RFP) process which was launched in March. A contract was signed with the successful proponent, TransCanada, in October 2009.

- The southwest GTA procurement process allowed the OPA to cancel the procurement at anytime with no financial penalty. The OPA provided the Ministry of Energy with opportunities not to proceed at each key decision point throughout the RFQ and RFP stages up to, and including, the execution of the contract with TransCanada.

Siting

- The OPA's procurement process established geographic boundaries within which a new gas-fired power plant had to be located in order to meet the electricity needs indentified in the IPSP and consistent with the Minister's directive. Power plant developers were required to identify a suitable site within those geographic boundaries which included south Oakville, south Mississauga and south Etobicoke.

- OPA has long advocated better coordination between land use planning and electricity planning through the development of community energy plans.

Environmental Protection

- The OPA's southwest GTA RFP, as well as the contract signed with TransCanada, required power plant developers to obtain all necessary approvals mandated by the Ministry of Environment. This included requirements set out in the Environmental Protection Act as well as the Ministry of Environment's regulations for emissions from stationary turbines.

- Additionally, the OPA required that the emissions standards for the southwest GTA power plant be 70% better than what the Ministry of Environment required at the time.

- Outside the procurement process, the OPA participated in the Clarkson Clean Air Task Force established by the Ministry of Environment and Ministry of Energy in November 2009, which examined opportunities to offset potential environmental impacts from the power plant.

Plant Safety

- The RFP, as well as the contract with TransCanada, required power plant developers to comply with all regulations and laws with respect to safety, as well as environmental protection and municipal approvals in place at that time in the province of Ontario.

- The RFP required power plant developers to work with either Union Gas or Enbridge to connect gas to the plant. Developers were not permitted under the procurement process, or the TransCanada contract, to build their own connection.

- The Technical Safety and Standards Authority inspects natural gas connections.

Community Consultation

- The procurement process required power plant developers to consult with community members and submit a community engagement plan as part of the proposal they submitted to the OPA.

- Additionally, the OPA held six community meetings in Oakville, Mississauga and Etobicoke, participated in a town hall hosted by the Mayor of Mississauga and took part in 22 formal meetings with ratepayers associations, municipal and provincial politicians and business leaders. Information about the procurement process and community meetings was also publicly available on the OPA's website.

Tab 11

Ontario Power Authority
Gas-Fired Power Plant Contracts

Procurement Process
The OPA's strong preference is to procure gas-fired generation through competitive procurement processes. The OPA's competitive procurements are carried out in two stages, a request for qualifications followed by a request for proposal. The RFQ and RFP as well as the contract are made public during the procurement process. After qualifying to participate in the RFP, power plant developers have 6 to 8 months to complete their proposals. Generally speaking, this time is spent identifying and verifying costs in order to develop a net revenue requirement (the monthly contract payment they require to build and operate the plant), securing financing and consulting the community.

An evaluation committee chaired by an independent third party, and overseen by a third party fairness advisor, evaluates the RFPs. The committee objectively reviews the proposals against criteria set out in the procurement documents to ensure that they comply with the procurement rules, that the net revenue requirement and the information it is built on is valid, that the financing arrangements are viable, and that other required information, including a community development plan, is valid, ultimately selecting the proposal that provides the highest value to ratepayers.

Net Revenue Requirement
The net revenue requirement (NRR) is the monthly payment that a power plant developer receives from the OPA. It is included in the developer's proposal/bid and set out in the contract. The NRR is intended to cover the costs of building and operating the plant, and depending on how efficiently the developer does this, provides the developer with a rate return.

Developer Financial Requirements
Under the OPA's contracts, power plant developers are responsible for all the upfront costs associated with planning and developing the plant. This means all the financial risks associated with building the plant are born by the developer. The power plant developer only starts receiving payments from the OPA once the plant is up and running, and then the payment is the previously agreed to NRR regardless of what it actually cost to build the plant. It generally takes three to four years for a power plant to be built after a contract is signed.

Environmental Approvals and Permitting
Under the OPA's contracts, power plant developers are responsible for obtaining all environmental approvals mandated by the Ministry of Environment. They are also responsible for obtaining all approvals required by the municipalities in which the plants are located.

Gas and Transmission Connections
Under the OPA's contracts, the costs to connect a power plant to the gas supply and the transmission system are covered by the power plant developer and included in the costs set out in the developers bid and ultimately are reflected in the NRR.

Gas Management & Delivery
Gas delivery and management (GD & M) are costs associated with transporting natural gas from the Dawn gas hub near Sarnia and managing it on the power plant site. In some instances these costs are

covered by the power plant developer and reflected in the NRR. In other cases, the OPA covers these costs and the NRR is reduced to reflect this.

Termination for Convenience
A termination for convenience clause would allow the OPA to terminate the contract even where the developer is not in default under the contract. The standard form of gas contract developed by the Ministry of Energy for the 2004 RFP process and the subsequent gas contracts entered into by the OPA do not have such a clause. In order for such a clause to not be viewed by developers and their financiers as creating unacceptable risks, it would likely have to provide for significant damages to be paid to the developer whenever a contract is terminated for convenience. Additionally, it could also result in a premium on bids, as developers add the additional risk into the price. Termination of the contract does not take away the developer's right to build the project. The developer's right to build the project depends on whether or not it has all of the necessary permits and approvals.

Force Majeure
A force majeure is something that prevents a party from performing its obligations under the contract and is beyond its reasonable control. All of the OPA gas contracts have provisions that address force majeure events. These clauses provided for timelines under the contract such as the date for commercial operation to be extended where a force majeure has occurred. These clauses also give rights to terminate the contract without payments by either party other than the return of security when a force majeure has existed for a significant period of time:

(i) If fm has delayed COD by more than a year, then developer may terminate the contract;
(ii) If fm has delayed COD by more than 2 years, then the OPA or developer may terminate the contract; and
(iii) If fm prevents developer from meeting obligations under the contract for more than 36 months in a 60-month period, then either party may terminate the contract.